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FILED ELECTRONICALLY

November 12, 2021

Ms. Steffany Powell Coker
Secretary to the Commission
Public Service Commission of Wisconsin
4822 Madison Yards Way
P.O. Box 7854
Madison, WI 53707-7854

Strategic Energy Assessment 2028 – Narrative Submission **5-ES-111**

Dear Ms. Powell Coker:

Northern States Power Company – Wisconsin ("NSPW"), a Wisconsin corporation, hereby submits the following required schedules, narratives and supplemental data request information:

- General Schedule Information – narrative description of transmission and generation resources and how Wisconsin-specific information is reported throughout the assessment
- Schedules 1 through 15 – completed SEA 2028 templates. Schedules 2 (including 2A through 2D), 4, 9, 12 and 13 are being filed in confidential and public redacted versions
- Schedule 10 – comprehensive narrative description of all planned energy efficiency activities
- Schedule 11 – narrative description for new transmission line projects that do not have a CPCN application or will be constructed in new right-of-way
- Schedule 12 – narrative description of the potential impacts of meeting environmental compliance rules. This is being filed in confidential and public redacted versions.
- Supplemental data request - description of carbon reduction activities
- Supplemental data request – description of reliability impacts of potential unit retirements
- Supplemental data request – description of utility resource planning

Please direct any questions to me at (715) 737-1113 or michelle.schlosser@xcelenergy.com.

Sincerely,

Michelle D. Schlosser
Regulatory Case Specialist

General Schedule Information: NSP System vs WI Resources

Northern States Power Company, a Wisconsin corporation (NSPW), together with Northern States Power Company, a Minnesota corporation, (NSPM) plans and operates an integrated five-state (Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan) system (the NSP System). NSPW and NSPM share generation and transmission resources for the NSP System pursuant to a Federal Energy Regulatory Commission (FERC)-approved Interchange Agreement (I/A).

The I/A specifies that NSPW and NSPM are allocated their proportionate share of costs for the NSP System according to the portion of the system that they represent for demand and load. NSPW represents approximately 16% of the NSP System and therefore is allocated approximately 16% of costs and resources of the NSP System.[1]

Per PSC 111.05(3), where Wisconsin-specific information was not available, NSPW reported prorated NSP System demand and load data based on the 16% allocation method defined in the I/A. Whereas information reported for transmission and generation facilities (ex: capacity purchases and sales, unit retirements, new build) were only those facilities located in Wisconsin or used specifically for Wisconsin purposes.

[1] The actual percentage allocators used for the I/A are updated annually for demand costs and monthly for energy costs, based on actual demand and energy data. The 16 percent used here is an approximation.

Assessment of Electric Demand and Supply Conditions - Historic

Instructions

SEA data collection pursuant to Wis. Admin. Code § PSC 111.11(2)(a)1-6, PSC 111.13, PSC 111.21(1)(b)-(f), PSC 111.23(2)(a)-(b), and PSC 111.41.
IOUs should include wholesale requirements customers' data.
Data for 2021 should represent January 1, 2021 to September 30, 2021.
Data for forecast years (2022-2028) should be entered on Schedule 2.
2019 data from the previous SEA represent 9 months of data and must be revised to reflect 12 months of data.
All 2020 data from the previous SEA represented a 12-month forecast and must be revised to reflect 12 months of actuals.
All 2021 data from the previous SEA represent 12-month forecast and must be revised to reflect 9 months of actuals (January 1 to September 30).
Peak load is defined as the Wisconsin load the provider would have served before implementing PSC 111.11(2a), items 2 through 6.
For Direct Load Control and Interruptible Load, report values for what was implemented or scheduled.
For Additional demand and additional supply, add a brief description.
For owned capacity, and merchant plant capacity under contract, include capacity located in state or used for Wisconsin customers.

Wisconsin Peak Electric Demand (MW)	2019	2020	2021
Date of Peak Load	7/15/2019	7/8/2020	6/8/2021
Peak Load MW, non-coincident	1,298	1,332	1,322
Direct Load Control Program	0.0	0.0	12.3
Interruptible load	0.0	0.0	0.0
Capacity sales, including reserves	0.0	0.0	0.0
Capacity purchases, including reserves	0.0	0.0	0.0
Transmission loss responsibility associated with purchases	0.0	0.0	0.0
Additional demand factor *(type description here)*	0.0	0.0	0.0
Adjusted electric demand	1298.4	1332.3	1334.0
Electric Power Supply (MW)			
Owned generating capacity	1108.7	1221.5	1129.0
Merchant power plant capacity under contract	0.0	0.0	0.0
Unit retirements	0.0	0.0	0.0
New: owned or leased capacity additions	0.0	0.0	0.0
Capacity changes at existing units	0.0	0.0	0.0
Capacity purchases without reserves, system basis	125.3	113.6	134.3
Capacity purchases without reserves, unit basis	298.1	228.5	337.9
Transmission loss responsibility associated with purchases	0.0	0.0	0.0
Capacity sales without reserves, system basis	-9.9	-14.9	-18.5
Capacity Sales without reserves, unit basis	0.0	0.0	0.0
Additional supply factor--scheduled outages	0.0	0.0	0.0
Additional supply factor *(type description here)*	0.0	0.0	0.0
Electric Power Supply	1522.2	1548.7	1582.8
Reserve Margin	17.23%	16.25%	18.65%
Resources Not Dispatched (MW)			
Direct Load Control Program	15.5300	16.1700	4.5600
Interruptible load	57.4500	64.5900	61.7300
Additional demand factors (type description here)	0.0000	0.0000	0.0000
Transmission : Firm Interface Capacity Counted for Reserves (MW)			
Resources using MINN/WUMS interface	0.0000	0.0000	0.0000
Resources using CE/WUMS interface	0.0000	0.0000	0.0000
Resources using Upper Michigan\Wisconsin interface	0.0000	0.0000	0.0000
Total	0.0000	0.0000	0.0000

Information in Lines 28 - 31 are already accounted for in Lines 27, 32-33 and 35.

Assessment of Electric Demand and Supply Conditions - Forecast

Based on MISO LSE Balance Sheet and PSC Resource Adequacy Reporting in 5-EI dockets
The worksheet below remains consistent with Schedule 2 in previous SEAs. Complete the new supporting worksheets in Schedule 2A-2D and ensure the information is consistent with the information on this worksheet.
Provide the most up-to-date data available at the time of response, including any updates from similar data filed in the spring OMS/MISO surveys.
Provide Wisconsin-specific data.
SEA data collection pursuant to Wis. Admin. Code. § PSC 111.21(1)(b) through (e), PSC 111.11(2)(a)1-3,5-6.
IOUs should include wholesale requirements customers' data.
EE and Smart Energy Program not eligible for capacity in the PRA.

Note: The data below is consistent with data reported in the OMS MISO Surveys on 4/15/2020 and 4/15/2021 for two load serving entities: NSPX and NSPP. NSPX is the load serving entity that serves three distinct wholesale customers, including one headquartered in Wisconsin, Dahlberg Light and Power Company (DLP). The data reported below under NSPX includes only the WI portion, namely DLP data. NSPP represents the NSP System's native load customers. The NSP System data has been prorated using the Company's Interchange Agreement percentage to report WI only data.

NSPX (DLP Only)	2021	2021	2022	2022	2023	2023	2024	2024	2025	2025	2026	2026	2027	2027	2028	2028
All Asset Owners for WEPM	ICAP	UCAP	ICAP	UCAP	ICAP	UCAP	ICAP	UCAP	ICAP	UCAP	ICAP	UCAP	ICAP	UCAP	ICAP	UCAP
Capacity (MW)																
High Certainty Resources (Existing Resource)																
Low Certainty Resources (Existing Resource)																
Behind the Meter (Existing Resource)																
DRR plus Registered DSM (Existing Resource)																
New Capacity DPP Signed GIA (New Resource)[1]																
New Capacity DPP GIA Phase (New Resource)																
New Capacity DPP Phase 3 (New Resource)																
New Capacity DPP Phase 2 (New Resource)																
New Capacity DPP Phase 1 / Not Started (New Resource)																
New Capacity Not in Interconnection Queue (New Resource)[2]																
New BTMG / NEW DR (New Resource)																
RZ Internal Transfer- In (ZRC)																
RZ Internal Transfer- Out (ZRC)																
External Resource Imports (Existing Resource)																
Total Committed Net Capacity (MW) Includes DPP Signed GIA																
Total Potential Net Capacity (MW)																
Demand (MW)[3]																
Non-Coincident Peak gross of DR																
Full Responsibility Transaction (FRT)																
Zonal Coincident Factor																
Coincident LSE Peak with Zonal Peak gross of DR																
MISO Coincident Factor																
Coincident LSE Peak to MISO Peak gross of DR																
Reserve Requirement (MW)																
Local Clearing Requirement[4]																
Planning Reserve Requirement																
PRMR																
UCAP to ICAP Conversion																
Reserve Margin (MW), as submitted with Signed GIA																
Resources above Local Clearing Requirement																
Resource above Planning Reserve Requirement																
Reserve Margin (MW), as submitted With Total Potential Resources																
Resources above Local Clearing Requirement																
Resource above Planning Reserve Requirement																

NSPP (WI portion only)	2021	2021	2022	2022	2023	2023	2024	2024	2025	2025	2026	2026	2027	2027	2028	2028
All Asset Owners for WEPM	ICAP	UCAP	ICAP	UCAP	ICAP	UCAP	ICAP	UCAP	ICAP	UCAP	ICAP	UCAP	ICAP	UCAP	ICAP	UCAP
Capacity (MW)																
High Certainty Resources (Existing Resource)																
Low Certainty Resources (Existing Resource)																
Behind the Meter (Existing Resource)																
DRR plus Registered DSM (Existing Resource)																
New Capacity DPP Signed GIA (New Resource)[1]																
New Capacity DPP GIA Phase (New Resource)																
New Capacity DPP Phase 3 (New Resource)																
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New Capacity Not in Interconnection Queue (New Resource)[2]																
New BTMG / NEW DR (New Resource)																
RZ Internal Transfer- In (ZRC)																
RZ Internal Transfer- Out (ZRC)																
External Resource Imports (Existing Resource)																
Total Committed Net Capacity (MW) Includes DPP Signed GIA																
Total Potential Net Capacity (MW)																
Demand (MW)[3]																
Non-Coincident Peak gross of DR																
Full Responsibility Transaction (FRT)																
Zonal Coincident Factor																
Coincident LSE Peak with Zonal Peak gross of DR																
MISO Coincident Factor																
Coincident LSE Peak to MISO Peak gross of DR																
Reserve Requirement (MW)																
Local Clearing Requirement[4]																
Planning Reserve Requirement																
PRMR																
UCAP to ICAP Conversion																
Reserve Margin (MW), as submitted with Signed GIA																
Resources above Local Clearing Requirement																
Resource above Planning Reserve Requirement																
Reserve Margin (MW), as submitted With Total Potential Resources																
Resources above Local Clearing Requirement																
Resource above Planning Reserve Requirement																

OMS - Existing Resources

MP	Asset Owner	LBA	Type	Resource Name	Fuel Type	Resource Type	Resource Zone	UCAP MW	2021 ICAP	UCAP	Factor	2022 ICAP	UCAP	Factor	2023 ICAP	UCAP	Factor	2024 ICAP	UCAP	Factor	2025 ICAP	UCAP	Factor	2026 ICAP	UCAP	Factor	2027 ICAP	UCAP	Factor	2028 ICAP	UCAP	Factor
[redacted]																																

OMS - New Resources										
MP	Asset Owner	Project Name	Resource Type	UCAP MW (Calculated)	ICAP MW	Year	LBA	DPP Study Phase	Pooled EFORD % (Calculated)	Comments
[redacted]										

OMS - ZRC Transactions

Contract Name	LBA	Seller MP	Seller AO	RZ Source	Buyer MP	Buyer AO	RZ Sink	Planning Resource Name	Fuel Type	Transfer Type	Existing	ZRC (UCAP)	Seller LBA	ZRC (ICAP)	2021 ICAP	UCAP	Factor	2022 ICAP	UCAP	Factor	2023 ICAP	UCAP	Factor	2024 ICAP	UCAP	Factor	2025 ICAP	UCAP	Factor	2026 ICAP	UCAP	Factor	2027 ICAP	UCAP	Factor	2028 ICAP	UCAP	Factor	Comments
[redacted]																																						

OMS - Full Responsibility Transactions																																		
Contract Name	Buyer MP	Buyer Asset Owner	RZ Source	Seller MP	Seller Asset Owner	FRT MW	LBA	2021 ICAP	UCAP	Factor	2022 ICAP	UCAP	Factor	2023 ICAP	UCAP	Factor	2024 ICAP	UCAP	Factor	2025 ICAP	UCAP	Factor	2026 ICAP	UCAP	Factor	2027 ICAP	UCAP	Factor	2028 ICAP	UCAP	Factor	Comments
[redacted]																																		

Assessment of Annual Energy Supply Conditions

Instructions

Include data through September 30, 2021
IOUs are to include wholesale requirements customers' data.
SEA data collection pursuant to Wis. Admin. Code. § PSC 111.07
2019 data from the previous SEA represent 9 months of data and must be revised to reflect 12 months of data.
All 2020 data from the previous SEA represented a 12-month forecast and must be revised to reflect 12 months of actuals.
All 2021 data from the previous SEA represent 12-month forecast and must be revised to reflect 9 months of actuals (January 1 to September 30).
All 2022 through 2026 data from the previous SEA represent 12-month forecasts and must be reviewed and revised to reflect current forecasts for these years.
Nothing on this form is expected to be confidential

	History		Current Year	Forecast						
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Owned Generating Energy Output (MWh)										
Coal	10,900,067	8,527,670	8,989,027	5,511,577	4,772,275	3,542,643	3,943,225	5,506,317	2,777,170	2,443,890
Nuclear	14,104,547	14,677,288	14,009,628	14,599,061	14,036,592	14,611,978	14,051,141	14,588,901	14,051,970	14,638,690
Natural Gas	8,655,279	6,834,399	5,757,214	4,947,359	6,397,944	5,511,041	4,906,358	4,343,246	6,111,570	5,766,070
Wind	3,136,720	4,969,964	7,121,192	8,361,634	8,996,196	9,120,829	8,994,212	9,150,002	9,144,530	9,168,620
Solar	0	0	0	6,058	126,381	587,129	1,035,413	1,030,970	1,053,110	1,020,320
Renewable Biomass or Biogas	550,344	553,608	512,893	441,393	460,649	462,281	479,557	480,087	489,760	255,690
Hydroelectric	1,256,161	1,247,700	887,723	933,246	933,246	934,764	933,246	933,246	933,250	934,770
Fuel Oil	5,017	2,231	13,258	0	0	0	0	0	360	300
Subtotal	38,608,136	36,812,860	37,290,934	34,800,328	35,723,283	34,770,666	34,343,152	36,032,768	34,561,720	34,228,350
Merchant Power Plant Energy Output under Contract (MWh)										
Coal	0	0	0	0	0	0	0	0	0	0
Natural Gas	2,726,481	3,716,440	3,576,752	3,408,515	3,484,148	3,432,476	3,143,080	2,934,129	2,193,050	1,982,660
Wind	4,560,934	5,543,240	5,182,696	6,740,532	6,008,945	6,001,524	5,942,034	5,910,922	5,875,130	5,773,600
Solar	1,351,695	1,788,659	2,047,916	2,344,059	2,788,426	3,648,300	4,782,740	4,941,038	5,085,510	6,019,130
Renewable Biomass or Biogas	449,644	413,030	439,056	401,274	364,168	364,091	0	0	0	0
Hydroelectric	1,387,992	1,389,138	1,713,311	1,901,671	1,904,199	1,915,409	606,687	141,642	141,670	141,890
Subtotal	10,476,745	12,850,507	12,959,731	14,796,050	14,549,885	15,361,801	14,474,541	13,927,731	13,295,360	13,917,280
Total Energy Output	49,084,881	49,663,367	50,250,665	49,596,378	50,273,168	50,132,467	48,817,693	49,960,500	47,857,080	48,145,630

Details of Purchases, Sales and Transmission Rights

Instructions:

For signed purchases and sales, which are reported on Schedule 1, provide details including any required transmission rights.
Provide transmission rights information for other capacity resources requiring transmission rights for delivery.
For potential, in progress, or expected, which ARE NOT reported on Schedule 1, provide details including any required transmission rights.
IOUs should include data for all wholesale requirements customers.
May be filed confidentially.
SEA data collection pursuant to Wis. Admin. Code § PSC 111.21(2)(a) 4 and 5 and § PSC 111.23(2) a and b
Report entries chronologically and report multi-year arrangements seperately, in each applicable year.
All 2019 data submitted for previous SEA represented 9 months of data and must be revised to reflect 12 months of data.
All 2020 data submitted in previous SEA represent a 12-month forecast and must be revised to reflect 12 months of actuals.
All 2021 data submitted in previous SEA represented 12-month forecast and must be revised to reflect 9 months of actuals (January 1 to September 30).
All contracts submitted for previous SEA should be reviewed and revised for accuracy.
New contracts must be added.

Purchase, Sale or Generation										Transmission Rights for Delivery of Purchases and Generation								
Contract Type	Year	Type	Counter-party ID	Counter-party Name	Start Date	End Date	Unit/ System	Firmness	MW	Fuel Type	EMRIT ID	Name	LSE	FTR Sink	Initial CFTR (MW)	Restricted Nomination (MW)	Unrestricted Nomination (MW)	Allocated (MW)	Notes
[redacted]																			

Assessment of Electric Demand and Supply Conditions Monthly Peak Demand (MW)

Instructions

Include data through September 30, 2021
IOUs are to include wholesale requirements customers' data.
SEA data Collection pursuant to Wis. Admin. Code § PSC 111.11(2)
Peak load is the Wisconsin load the electric provider would have served before implementing § PSC 111.11(2a)2 through 6
All 2019 data submitted for previous SEA represented 9 months of data and must be revised to reflect 12 months of data.
All 2020 data submitted in previous SEA represent a 12-month forecast and must be revised to reflect 12 months of actuals.
All 2021 data submitted in previous SEA represented 12-month forecast and must be revised to reflect 9 months of actuals (January 1 to September 30)
Green-highlighted cells reflect actuals.
Nothing on this form is expected to be confidential

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Historical:												
2019	1,136	1,066	1,079	994	973	1,066	1,298	1,187	1,098	937	1,041	1,073
2020	1,056	1,070	956	855	988	1,256	1,332	1,247	961	937	964	1,052
Forecasted:												
2021	1,037	1,098	976	877	1,039	1,322	1,229	1,214	1,119	920	955	1,065
2022	1,090	1,037	1,019	921	1,028	1,295	1,339	1,298	1,125	920	958	1,066
2023	1,078	1,054	991	909	1,029	1,315	1,371	1,324	1,142	928	962	1,073
2024	1,071	1,026	975	896	1,015	1,313	1,417	1,332	1,136	921	952	1,064
2025	1,055	1,011	960	879	997	1,305	1,376	1,338	1,125	910	940	1,053
2026	1,048	998	950	870	987	1,306	1,382	1,344	1,117	900	930	1,043
2027	1,042	986	944	861	978	1,308	1,391	1,354	1,114	895	924	1,038
2028	1,041	976	942	857	972	1,314	1,404	1,369	1,113	895	922	1,036

Assessment of Energy Conditions Monthly Energy (MWH)

Instructions

Include data through September 30, 2021
IOUs are to include wholesale requirements customers' data.
Data in this schedule is the Wisconsin load the electric provider would have served before implementing § PSC 111.11(2a)2 through 6.
SEA data collection pursuant to Wis. Admin. Code § PSC 111.07
All 2019 data submitted for previous SEA represented 9 months of data and must be revised to reflect 12 months of data.
All 2020 data submitted in previous SEA represent a 12-month forecast and must be revised to reflect 12 months of actuals.
All 2021 data submitted in previous SEA represented 12-month forecast and must be revised to reflect 9 months of actuals (January 1 to September 30).
Green-highlighted cells reflect actuals.
Nothing on this form is expected to be confidential

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Historical:												
2019	664,517	601,967	621,289	547,924	548,157	573,860	680,084	642,285	580,319	567,657	582,906	618,144
2020	631,113	593,528	575,860	496,921	505,927	585,710	689,859	652,171	533,989	563,546	551,993	622,930
Forecasted:												
2021	626,720	605,479	577,199	511,978	547,788	656,622	659,197	649,141	568,475	580,493	561,784	616,058
2022	643,804	574,172	613,167	552,677	579,766	606,395	682,238	668,942	568,608	578,490	560,295	614,518
2023	645,512	575,800	614,964	554,397	581,224	607,876	683,854	670,516	570,092	579,677	561,778	616,044
2024	647,064	588,332	613,000	555,702	582,846	609,584	685,901	672,762	571,768	581,407	563,002	617,599
2025	648,195	570,661	614020.6	556,945	584,187	610,555	687,020	673,742	572,877	582,652	564,079	618,624
2026	648,056	570,591	613,905	556,939	584,018	610,498	687,006	673,580	572,862	582,663	564,113	618,671
2027	648,340	570,887	614,179	557,285	584,221	610,779	687,272	673,832	573,189	582,867	564,395	618,953
2028	649,145	590,181	615,068	557,773	584,989	611,803	688,170	675,004	573,940	583,619	565,249	619,867

Unit Retirements, Upgrades, Fuel Switching

Instructions

Provide data for plants expected to be retired, upgraded, or switched to a different fuel by December 2028

SEA data collection pursuant to Wis. Admin. Code § PSC 111.21

Nothing on this form is expected to be confidential

Capacity Change: Retirement, Upgrade, Fuel Change

Only reported new generation located in WI or used specifically for WI purposes. Provided information on facilities with 10 MW or more in capacity. This included facilities where the combined capacity of units to be retired or upgraded is 10 MW or more, even though individual units may have a smaller capacity rating.

	Name of Facility	Capacity Change	Unit #	Location	Primary Fuel Type	Nameplate Capacity (MW)	Expected Annual Generation (kWh) *	Expected Year	Expected CO2 (lbs/kWh)	Nameplate Added Capacity (MW)	Expected Nameplate Capacity (MW)	New Primary Fuel Type
Retirement	Wheaton 6	Retirement	6	Eau Claire, WI	Oil	70		2025	N/A	N/A	N/A	N/A
	Wheaton 4	Retirement	4	Eau Claire, WI	Natural Gas	61		2025	N/A	N/A	N/A	N/A
	Wheaton 3	Retirement	3	Eau Claire, WI	Natural Gas	56	33,898,000	2025	N/A	N/A	N/A	N/A
	Wheaton 2	Retirement	2	Eau Claire, WI	Natural Gas	68		2025	N/A	N/A	N/A	N/A
	Wheaton 1	Retirement	1	Eau Claire, WI	Natural Gas	56		2025	N/A	N/A	N/A	N/A
Upgrade	NONE to Report											
Fuel Change	NONE to Report											

* Expected Annual Generation reported is based on actual annual generation, exclusive of plant use, for Year 2020 as reported on Schedule E-17, page 4, Line 9, of NSPW's Annual Report to the PSCW.

New Generating Facilities

Instructions:

Provide data for all new plants expected to commence construction and/or be placed in commercial operation prior to December 31, 2028
Do not enter existing facilities that are switching fuel here; use schedule 7.
SEA data collection pursuant to Wis. Admin. Code § PSC 111.21
In-service date refers to the year the unit or facility is expected to be commerically operational.
Review, revise and add data as appropriate.
Nothing on this form is expected to be confidential

Only reported new generation that is owned, no PPAs. (PPAs reported on Schedule 4)
Only reported new generation located in WI or used specifically for WI purposes.
Distributed generation resources only reported in Sch 13 and 14
This schedule is not limited to generation of 10MW or more like Sch 7 is.

Name of Facility	Unit #	Cost ($/kW)	City	State	Primary Fuel Type	Summer Net-Rated Capacity MW	Winter Net-Rated Capacity MW	Expected Annual Generation (kWh)	Expected In-Service Year	CO2 (pounds per kWh)
Western Mustang		$1,285	Pierce County	WI	Solar	74	74	Confidential See Docket No. 4220-SB-100	2022	N/A
Wheaton		Unknown	Eau Claire	WI	Natural Gas	Unknown	Unknown	Confidential See Docket No. 4220-SB-100	2025	Unknown

Existing Generating Facilities

Instructions

Enter information in separate rows for all utility generating facilities. Consistent with PSC annual report requirements, record separate rows by unit for large plants and record small plants in a single-row aggregate, not by unit.
For plants equipped with combinations of different generating fuels, report information for each fuel in a separate row.
Only report data for plants that were in service for all, or a portion, of 2020. Include all facilities operating in 2020 even if Schedule 7 indicates they will be retired in future years.
New facilities that will not begin operating until future years do not need to be entered here and can be documented in Schedule 8.
Enter Latitude, Longitude in Decimal Degrees, with a comma separating the two values.
When applicable, information on capacity, generation and cost of plant should be consistent with the information reported for generating plant statistics in PSC annual reports.
When applicable, information on CO2 emissions should be consistent with that reported in other state and federal sources (such as WI DNR and EIA). Explain any complications or inconsistencies in the notes column.
If net peak demand for 60 minutes is not available, provide data that is available, and specify the period in the notes column.

Only reported new generation that is owned, no PPAs. (PPAs reported on Schedule 4)
Only reported new generation located in WI or used specifically for WI purposes.
Distributed generation resources only reported in Sch 13 and 14

Name of Facility	Unit #	1st Year Commercial Operation	Street Address	City	State	Latitude, Longitude	Primary Fuel Type	Total Cost of Plant- 2019	Total Cost of Plant- 2020	Nameplate Capacity (MW)	Summer Net-Rated Capacity MW	Winter Net-Rated Capacity MW	Annual Net Generation, Exclusive of Plant Use (KWh) - 2019	Annual Net Generation, Exclusive of Plant Use (KWh) - 2020	Fuel Type Units (Coal-tons/Oil-barrel/Gas-mcf/etc.)	Quantity (units of Fuel Burned)- 2019	Quantity (units of Fuel Burned)- 2020	CO2 (pounds per kWh)- 2019	CO2 (pounds per kWh)- 2020	Net Peak Demand on Plant - MW (60 minutes)	Plant Hours to Connected to Load- 2019	Plant Hours Connected to Load- 2020	Net Continuous Plant Capability (MW)	Notes
Bay Front Plant	5	1954	122 N. 14th Ave West	Ashland	WI	46.58683, -90.901367	Biomass	86,075,091	89,404,627	20.73	18	18	88,810,700	83,823,500	Biomass-tons	248,540	230,053	3.641	3.273	60	8,413	8,372	41	
Bay Front Plant	5														Coal-Tons	1,524	4,197	See above, aggregate of all fuel types	See above, aggregate of all fuel types	see above	see above	see above	see above	
Bay Front Plant	5														Gas-MCF	27,733	29,785	See above, aggregate of all fuel types	See above, aggregate of all fuel types	see above	see above	see above	see above	
Bay Front Plant	6	1952	122 N. 14th Ave West	Ashland	WI	46.58683, -90.901367	Biomass	Included in above	Included in above	26.48	23	23	96,784,670	91,196,990	Biomass-tons	Included in above	Included in above	3.637	3.590	see above	see above	see above	see above	
Bay Front Plant	6														Coal-Tons	Included in above	Included in above	See above, aggregate of all fuel types	See above, aggregate of all fuel types	see above	see above	see above	see above	
Bay Front Plant	6														Gas-MCF	Included in above	Included in above	See above, aggregate of all fuel types	See above, aggregate of all fuel types	see above	see above	see above	see above	
French Island	1	1940	200 South Bainbridge St	La Crosse	WI	43.829640, -91.260170	Biomass	58,443,657	59,797,597	17.13	9	9	30,731,993	17,285,341	Biomass-tons	61,661	52,889	4.893	5.991	17	5,754	5,595	16	French Island Units 3 and 4 had zero (0) KWh net generation in 2020.
French Island	1														RDF-tons	46,593	51,856	See above, aggregate of all fuel types	See above, aggregate of all fuel types	see above	see above	see above	see above	
French Island	1														Gas-MCF	3,611	4,178	See above, aggregate of all fuel types	See above, aggregate of all fuel types	see above	see above	see above	see above	
French Island	2	1940	200 South Bainbridge St	La Crosse	WI	43.829640, -91.260170	Biomass	Included in above	Included in above	13.32	7	7	29,936,890	39,754,768	Biomass-tons	Included in above	Included in above	4.986	3.801	see above	see above	see above	see above	
French Island	2														RDF-tons	Included in above	Included in above	See above, aggregate of all fuel types	See above, aggregate of all fuel types	see above	see above	see above	see above	
French Island	2														Gas-MCF	Included in above	Included in above	See above, aggregate of all fuel types	See above, aggregate of all fuel types	see above	see above	see above	see above	
Wheaton	1	1973	3008 80th St	Eau Claire	WI	44.885727, -91.515995	Natural Gas	56,189,902	57,415,035	46.47	44	56	2,974,000	7,487,000	Gas-MCF	219,174	497,582	2.275	1.778	231	272	417	309	Wheaton Unit 6 had zero (0) KWh net generation in 2020.
Wheaton	1														Fuel Oil-barrels	8,804	1,284	See above, aggregate of all fuel types	See above, aggregate of all fuel types	see above	see above	see above	see above	
Wheaton	2	1973	3008 80th St	Eau Claire	WI	44.885727, -91.515995	Natural Gas	Included in above	Included in above	53.86	51	66	5,484,000	8,697,000	Gas-MCF	Included in above	Included in above	2.113	1.794	see above	see above	see above	see above	
Wheaton	2														Fuel Oil-barrels	Included in above	Included in above	See above, aggregate of all fuel types	See above, aggregate of all fuel types	see above	see above	see above	see above	
Wheaton	3	1973	3008 80th St	Eau Claire	WI	44.885727, -91.515995	Natural Gas	Included in above	Included in above	46.47	44	56	2,962,000	8,006,000	Gas-MCF	Included in above	Included in above	2.076	1.825	see above	see above	see above	see above	
Wheaton	3														Fuel Oil-barrels	Included in above	Included in above	See above, aggregate of all fuel types	See above, aggregate of all fuel types	see above	see above	see above	see above	
Wheaton	4	1973	3008 80th St	Eau Claire	WI	44.885727, -91.515995	Natural Gas	Included in above	Included in above	49.64	47	61	3,740,000	10,206,000	Gas-MCF	Included in above	Included in above	2.013	1.750	see above	see above	see above	see above	
Wheaton	4														Fuel Oil-barrels			See above, aggregate of all fuel types	See above, aggregate of all fuel types	see above	see above	see above	see above	
Chippewa Falls		1928	100 Court St.	Chippewa Falls	WI	44.932114, -91.389177	Hydro	15,074,199	15,126,058	21.6	12	12	85,921,000	88,817,000						22	8,743	8,775	12	
Cornell		1976	N 45 09.854 W 91 09.407	Cornell	WI	45.164240, -91.156778	Hydro	22,365,622	22,394,377	35.3	20	20	128,587,000	124,235,000						31	8,222	8,375	20	
Eau Claire Dells		1907	1120 Forest St.	Eau Claire	WI	44.828128, -91.510809	Hydro	35,284,772	35,288,809	12.43	7.2	7.2	61,029,000	61,511,000						11	8,704	8,760	7	
Holcombe		1950	2732 263rd Avenue	Holcombe	WI	45.224112, -91.127518	Hydro	15,058,384	15,084,876	33.75	22	22	150,331,000	139,222,000						35	6,874	7,683	22	
Jim Falls		1923	19760 Cty Hwy S.	Jim Falls	WI	45.051138, -91.274066	Hydro	108,100,754	108,319,537	59.8	25	25	212,075,000	192,359,000						55	7,961	8,168	25	
St. Croix Falls		1905	130 River Street North	St. Croix Falls	WI	45.411911, -92.647061	Hydro	18,133,852	18,329,946	23.2	15	12	127,400,000	130,622,000						23	8,725	8,779	15	
Wissota		1917	6350 163rd Street	Chippewa Falls	WI	44.938007, -91.340639	Hydro	28,665,050	30,773,859	39.47	18	18	205,664,000	198,999,000						40	8,760	8,784	18	
Apple River		1901	2040 County Road I	Somerset	WI	45.155960, -92.709332	Hydro	4,797,001	4,797,001	2.25	1.3	1.6	12,460,800	14,326,000						3.2	4968	6235	1.3	Smaller plants not connected to EMS are displaying Avg Unit Hours for the year in columns W and X
Big Falls		1922	W 5506 Dam Rd.	Glen Flora	WI	45.555691, -90.959721	Hydro	12,038,164	12,038,164	7.78	3.3	2.9	32,787,520	43,337,000						8.5	4782	6267	3.3	Smaller plants not connected to EMS are displaying Avg Unit Hours for the year in columns W and X
Cedar Falls		1910	7075 540th St	Menomonie	WI	44.935676, -91.888844	Hydro	6,785,535	6,785,535	6	3.6	3.4	46,944,000	44,176,000						7.3	7719	8028	3.6	Smaller plants not connected to EMS are displaying Avg Unit Hours for the year in columns W and X
Hayward		1910	N 46 00.404 W 91 29.070	Hayward	WI	46.006745, -91.484489	Hydro	1,431,811	1,431,811	0.18	0.2	0.2	103,970	1,537,000						0.2	1015	8705	0.2	Smaller plants not connected to EMS are displaying Avg Unit Hours for the year in columns W and X
Ladysmith		1941	N 45 27.830 W 91 05.052	Ladysmith	WI	45.464820, -91.083237	Hydro	6,419,147	6,419,147	3.4	1	0.8	14,529,000	15,770,000						2.9	7136	7053	1	Smaller plants not connected to EMS are displaying Avg Unit Hours for the year in columns W and X
Menomonie		1958	800 2nd St. NW	Menomonie	WI	44.884043, -91.929656	Hydro	9,022,865	9,022,865	5.4	2.3	2.3	31,704,000	30,737,000						5.4	8429	8548	3.3	Smaller plants not connected to EMS are displaying Avg Unit Hours for the year in columns W and X
Riverdale		1905	N 45 07.894 W 92 38.430	Somerset	WI	45.131602, -92.640492	Hydro	1,024,942	1,024,942	0.5	0.3	0.3	3,507,000	3,533,000						0.6	7588	7958	0.3	Smaller plants not connected to EMS are displaying Avg Unit Hours for the year in columns W and X
Saxon Falls		1912	15462 N. Saxon Falls Rd	Saxon	MI	46.539195, -90.374386	Hydro	3,726,526	3,726,526	1.55	1	1.2	11,362,000	12,622,000						1.2	7975	8760	1	Smaller plants not connected to EMS are displaying Avg Unit Hours for the year in columns W and X
Superior Falls		1917	112 East Lake Road	Ironwood	MI	46.559867, -90.414945	Hydro	567,191	2,465,642	1.5	1	1.3	11,520,000	12,429,000						1.5	7797	8157	1	Smaller plants not connected to EMS are displaying Avg Unit Hours for the year in columns W and X
Thornapple		1927	W5506 Dam Road	Bruce	WI	45.411049, -91.218004	Hydro	4,267,445	4,267,445	1.4	0.8	0.8	9,784,000	10,131,000						1.7	8552	4333	0.8	Smaller plants not connected to EMS are displaying Avg Unit Hours for the year in columns W and X
Trego		1926	N8656 Ricci Rd	Trego	WI	45.947967, -91.888348	Hydro	1,894,146	1,894,146	1.2	0.7	0.7	9,802,000	9,275,000						1.5	8716	8419	0.7	Smaller plants not connected to EMS are displaying Avg Unit Hours for the year in columns W and X
White River		1907	N 46 29.862 W 90 54.562	Ashland	WI	46.497700, -90.909367	Hydro	2,225,270	2,225,270	1	0.4	0.5	5,304,000	6,173,000						0.6	7314	8716	0.4	Smaller plants not connected to EMS are displaying Avg Unit Hours for the year in columns W and X

Economic Data

Instructions

SEA data collection pursuant to Wis. Admin. Code § PSC 111.31(1)
Include data through September 30, 2021
Report data on this page in $/MWh. Data should reflect fuel only.
Forecast data may be either developed from public sources, or internal and proprietary. Regardless of forecast method, figures should be developed in a manner consistent with historical figures.
All 2019 data submitted for previous SEA represented 9 months of data and must be revised to reflect 12 months of data.
All 2020 data submitted in previous SEA represent a 12-month forecast and must be revised to reflect 12 months of actuals.
All 2021 data submitted in previous SEA represented 12-month forecast and must be revised to reflect 9 months of actuals (January 1 to September 30).
May be filed confidentially.

	Average Energy Production Cost ($/MWh)									
	Actual		Forecast							
Type of Existing Unit	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
[redacted]										

Energy Efficiency Data

Instructions:
SEA data collection pursuant to Wis. Admin. Code § PSC 111.07.
Include data through September 30, 2021
Report all data in dollars.
Upload to ERF a comprehensive description of all planned activities to discourgage ineffective and excessive electric power use.
Nothing on this form is expected to be confidential

		Actual		Actual or Forecast	Forecast						
Item	**Notes**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Act 141 Dollars Contributed to Focus on Energy	#1	9,468,093	9,367,981	7,249,055	9,731,573	9,731,573	9,731,573	9,731,573	9,731,573	9,731,573	9,731,573
Utility Energy Efficiency Activity											
Act 141 dollars retained by electric provider	#2	0	0	0	0	0	0	0	0	0	0
Customer Service Conservation dollars	#3	842,596	795,793	509,707	855,702	855,702	855,702	855,702	855,702	855,702	855,702
Additional conservation and efficiency dollars	#4	1,992,330	1,797,014	1,268,305	2,323,383	2,323,383	2,323,383	2,323,383	2,323,383	2,323,383	2,323,383
Total Utility Spending (#2, #3, and #4 only)		2,834,926	2,592,807	1,778,012	3,179,085	3,179,085	3,179,085	3,179,085	3,179,085	3,179,085	3,179,085
Energy Savings (kWh) (Funded with #2, #3 and #4 only)	#5	0.00	0 00	0.00	0 00	0.00	0.00	0 00	0.00	0.00	0.00
Demand Savings (kW) (Funded with #2 and/or #4 only)	#5	0.00	0 00	0.00	0 00	0.00	0.00	0 00	0.00	0	0

Notes

#1: For investor-owned utilities, report actual contributions and projections based on anticipated trends in utility operating revenues. For municipal electric utilities and electric co-operatives that chose to contribute to Focus on Energy, contributions should be approximately $8/meter.

#2: For municipal utilities and retail cooperatives, these are dollars to provide commitment to community programs under 2005 Wisconsin Act 141 (Act 141). Only report dollars for energy efficiency and low-income weatherization. For investor-owned utilities, these are dollars for large energy customer programs provided by the utility under Act 141.

#3: Applicable only for class A investor-owned utilities (see Commission's August 17, 2000 Order in docket 05-BU-100).

#4: These are dollars to provide energy efficiency programs that are in addition to those required under Act 141. It includes voluntary expenditures on utility-administered programs, voluntary Focus on Energy contributions and dollars for ordered programs.

#5: Energy and demand savings to be reported are only those savings resulting from expenditures reported on this form. Reported figures should reflect only voluntary utility programs funded by #2 and #4 on this form.

Xcel Energy® RESPONSIBLE BY NATURE™

Voluntary Utility Program Filing
Wisconsin Admin Code PSC 137.08
2022 Community Conservation Program
Docket No. 4220-EE-2022
June 24, 2022

2022 Voluntary Community Conservation Program Filing

Xcel Energy continues to be a national leader in energy conservation; offering a comprehensive portfolio of efficiency and demand-side management programs for customers throughout our service territory. We are dedicated to helping customers manage their energy consumption through one of the largest energy saving program portfolios in the United States. Customers save money and we avoid emissions and the need to purchase, build or produce additional power. It's critical in our continuously evolving industry that we continue to help our customers understand the benefits of energy efficiency programs and make it as easy as possible to take advantage of them.

Northern States Power Company, a Wisconsin Company (NSPW) and wholly owned subsidiary of Xcel Energy, Inc. has a legacy of providing energy efficiency programs to our customers in Wisconsin. Since the inception of the statewide efficiency program, Focus on Energy (Focus), we have partnered our Voluntary Community Conservation Program (CCP) with Focus programming to provide incentives, bring greater awareness of energy conservation and to bring efficiency education to customers in our service territory.

NSPW continues to ensure each year that the CCP is cost-effective and beneficial to our customers. The Commercial sector continues to achieve a cost-effectiveness score that exceeds the goal, which was updated for the 2020 program year. However, the last two years has shown a decline in the cost-effectiveness score for the residential sector. Residential program lift has also not recovered back to the pre-2017 level when the CCP bonus was reduced from 80% to 60%. Although the evaluation shows we're still reaching customers and delivering both energy savings and a positive customer experience, NSPW addresses the cost-effectiveness and lift erosion in Sections One and Two.

As required in the Public Service Commission of Wisconsin's Administrative Code 137.08, this filing requests approval of our 2022 Voluntary CCP; with an anticipated effective date of January 1, 2022.

The information provided includes the following sections: Section One – Overall CCP Program Details, Section Two - Residential CCP Specifics, Section Three - Commercial CCP Specifics, Section Four – Mid-Market Program Specifics and Section Five – Pilot Program Proposal.

SECTION ONE 2022 Community Conservation Program (CCP) – Overall Program Details	
General Program Description	The NSPW CCP provides additional opportunities for residential and small to medium commercial and industrial customers who participate in Focus programs. It also helps bring Focus program information to areas of our service territory that may have not otherwise been reached by standard Focus marketing efforts.
Goals and Measures	The goals for the 2022 CCP are below: 1. Ensure the CCP is influencing NSPW customers to participate in energy conservation measures and to take advantage of the Focus programs and incentive dollars available to them. a. Program participation is measured through tracking overall NSPW customer participation in both Focus and CCP programs. Because the CCP is offered in conjunction with Focus programs, participation is primarily tracked through the Focus Utility Reporting Portal and/or reports from program implementers. NSPW also tracks bonus incentive payouts in our SalesForce system. b. Results are analyzed and compared with historical data to ensure consistent or increased participation in all categories. c. Analysis of available data on other utilities' customer participation in Focus programs is also considered in comparison to NSPW results. 2. Contract with Cadmus to conduct an evaluation of the 2022 program which includes both free-ridership and cost-effectiveness: a. Evaluation Plan with Cadmus for third-party evaluation requirements of 2022 program to be finalized and filed with Commission in Q3 2021, once full details of this 2022 program filing are finalized and can be included in the evaluation scope of work. b. NSPW will work with Commission staff on evaluation development. c. Evaluation will take place Q1 and Q2 of 2023. d. Provide a copy of the Cadmus Evaluation Report to Commission upon completion in Q2 2023. e. Evaluation results will be used to influence handling of 2023 program and 2024 program planning. 3. Goals for cost-effectiveness based on Cadmus findings in the

	2022 program evaluation: a. Findings from the last two evaluations (program years 2019 and 2020) indicate that it's unlikely NSPW will be able to achieve a residential cost-effectiveness score of 3.0 going forward. Due to the lower benefits from the lower avoided costs, NSPW's residential UAT score has been below 3.0 for the past two years. Based on these results, NSPW would like the Commission to consider an adjustment to the residential UAT score. b. As stated earlier, the commercial program continues to achieve a cost-effectiveness score greater than the goal. NSPW is not proposing a change to commercial and will continue with the current goal of a UAT score of at least 8, when calculated without Focus administrative costs. c. The second target is that the residential program's NTG score will be not fall below 50% and the commercial program will not fall below 70%. 4. Budget vs. expenditure tracking analysis: a. Ensure expenditures are in line with commission approved budgets. b. Analyze to ensure dollars spent on program administrative costs, advertising and EM&V are in line with program delivery costs. 5. File quarterly reports to the Commission and include overall results in the NSPW Customer Service Conservation Annual Report.
Marketing, Promotion & Communication	NSPW works with Focus program administrative staff to coordinate with and complement their marketing, promotion and communication efforts in addition to targeting areas in our smaller or rural customer territories which Focus may not reach. Promotion efforts may include: • Advertising o Print o Radio o Newsletters o Bill inserts/e-bill onserts o Direct Mail o Social Media • Community Involvement o Home Shows o Chamber Events o School Events o Sponsorships

	○ Community Events ○ Semi-annual trade ally meetings – winter/summer (6 throughout service territory)

SECTION TWO 2022 Community Conservation Program (CCP) – Residential Sector Specifics		
General Program Description	The Residential Sector of the CCP is designed to increase our residential customers' overall awareness of, and participation in, Focus programs. We also provide bonus incentives to further motivate and financially assist customers who participate in specific energy saving measures. Labor costs for this sector includes an appropriate percentage of time for: • Manager, DSM & Energy Efficiency Programs • Project Coordinator • Energy Expert Agents • Community Service Manager involved in the proposed Tribal Pilot explained in Section Five	
Target Market	Residential customers throughout our service territory may be served by this program.	
Home Performance with ENERGY STAR Program	The 2020 evaluation results show a drop in program lift. The downward decline in this area began in 2017 when the residential bonus incentive was dropped from 80% to 60%. It recovered slightly in 2018 but dropped again in 2019 and 2020. In an attempt to increase our impact on participation, NSPW is proposing to increase the bonus incentive to eligible customers participating in the 2022 Focus Residential Program from 60% to 75% in 2022. A budget increase would not be necessary for this proposal alone, however, combined with the proposed Tribal Pilot, a $30,000 increase to the incentive budget is being requested. (As in the past, total combined (Focus and NSPW) incentives may not exceed 90% of the total project cost.) The incentive amount, advertising and evaluation line items include additional dollars for the proposed Tribal Pilot explained in Section Five.	
Estimated Annual Budget	Residential CCP Labor: Rebates/Incentives: Advertising/Program Delivery: Voluntary Program Evaluation (EM&V) - Cadmus Total Program Costs:	$ 29,663 $ 620,000 $ 65,000 $ 50,804 $ 765,467

SECTION THREE 2022 Community Conservation Program (CCP) – Commercial Sector Specifics	
General Program Description	The Commercial Sector of the CCP is designed to increase our small to medium commercial and industrial customers overall awareness of, and participation in, Focus programs. We offer bonus incentives to aid with the initial cost of installing qualifying energy efficient equipment under the Focus Business and Industry Program. Labor costs for this program include an appropriate percentage of time for: • Manager, DSM & Energy Efficiency Programs • Project Coordinator • Community Service Manager involved in the proposed Tribal Pilot explained in Section Five
Target Market	Small to medium commercial and industrial customers throughout our service territory who qualify for the Focus Business and Industry Program are eligible for the Commercial sector of the CCP.
Business and Industry Program	NSPW will continue offering bonus incentives to eligible commercial and industrial customers who participate in the 2022 Focus Business and Industry Program. • NSPW will offer a bonus incentive equal to 50% of the Focus incentive, up to $4,000 per customer premise.
Mid-Market Targeting Bonus	NSPW would like to continue an additional bonus incentive for those customers who participate in the Focus Business and Industry Program as a result of the targeting that will be done in 2022 by the Mid-Market Program. The additional bonus incentive would be equal to an additional 25% of the Focus incentive, making the total bonus incentive from NSPW equal to 75% of the Focus incentive for the target markets. Target markets in 2021 consisted of agricultural customers, customers completing an assessment and completing a project within 6 months and customers in a community going through the implementation phase of the Partners in Energy (PiE) process. Targeting for 2022 will be defined after more information is attained as a result of the 2021 targeting but will likely include similar target markets. As of the time of this filing, 8 projects have qualified for the additional 25% bonus which has amounted to $685 in additional incentives. There are currently another 50 projects in the pipeline that qualify for the targeting bonus with more expected to be added throughout the year. The advertising and evaluation line items have been increased to reflect expected expenditures in the proposed Tribal Pilot explained in Section Five. The budget for labor and incentives was not increased due to both areas being underspent in the past.

Estimated Annual Budget	Commercial CCP Labor:	$ 589,933
	Rebates/Incentives:	$ 926,679
	Advertising/Program Delivery:	$ 40,000
	Voluntary Program Evaluation (EM&V) - Cadmus	$ 50,804
	Total Program Costs:	$ 1,607,416

SECTION FOUR 2022 Community Conservation Program (CCP) – Mid-Market Program	
General Program Description	This program is designed to provide dedicated resources in order to engage small and medium size commercial and industrial customers and create a deeper awareness of the benefits of energy efficiency, causing greater participation in the Focus programs. Labor costs for this program include all charges for the following five positions and are included in the Commercial CCP Labor section: • One Mid-Market Team Lead • Four Mid-Market Field Reps
Target Market	The target market for the Mid-Market Program (MMP) is all commercial and industrial customers that are not managed by a dedicated NSPW Account Manager (LEU), and that are eligible for the Focus Business and Industry Program.
Mid-Market Program	Through the Mid-Market Field Rep, NSPW is providing a resource that will manage the DSM relationship with mid-market customers, providing them with detailed information, recommendations and solutions concerning their energy utilization needs, including promotion of the Focus commercial programs. The Field Rep responds to customer needs primarily through on-site visits and other channels of influence including inbound and outbound calling. The Team Lead is the liaison between Focus staff and the Field Reps and holds regular meetings to ensure consistent communication. The Team Lead is also responsible for gathering and providing feedback in order to refine the targeting campaigns to maximize effective delivery of the MMP. They are also responsible for monitoring, supporting and developing the Field Reps to ensure the MMP objectives are being accomplished.
Estimated Annual Budget	The budget for the MMP is made up of labor, incentives, promotion and administrative expenses. All MMP expenses are captured within the Commercial CCP Estimated Annual Budget.
Goals and Measures	The MMP has been integrated into the existing CCP in terms of budget and cost effectiveness measures, but is responsible for its own participation

	goals. The ultimate goal of the MMP is to drive customers to the Focus Business and Industry Program. Outlined below are the proposed quantitative goals for 2022. • Drive one-on-one customer contacts to project completion at a rate of 15% (i.e. 15 completed projects for every 100 personal contacts) • Influence 30% of participants in the Business and Industry Program (i.e. for every 100 participants in this program, 30 will have worked with MMP)

SECTION FIVE **2022 Community Conservation Program (CCP) – Pilot Proposal**	
Tribal Community Pilot with Focus on Energy	NSPW continues to look for ways to expand the CCP offering in order to impact areas that could benefit from additional support and may not be easily reached by Focus programming. To help with planning for the 2022 CCP, NSPW had conversations with PSC and Focus Staff to brainstorm ideas. An area that stood out that could benefit from more support were the low- and moderate-income households and rural businesses. At the same time, Focus shared their interest in using carryover dollars to target tribal communities in Wisconsin. Knowing the economic situation in the tribal communities and their infrastructure of small, tribal owned-businesses, NSPW realized that a program specifically targeting these communities would address the low- to moderate-income households and rural businesses need. NSPW and Focus began conversations to discuss a possible collaborative effort, enlisting the help of NSPW's Community Service Manager (CSM) that serves the tribal communities in our service territory. The CSM has an excellent relationship with the tribal communities which will be critical in outreach efforts. Tribal communities can be difficult to reach and are typically not receptive to 'outsiders'; having someone with an existing relationship to help 'get our foot in the door' could prove very valuable in building trust. Through conversations with Focus, the preferred course of action is to target one community with a select group of offerings and gauge the tribe's interest and participation prior to possible expansion to other tribes. Our CSM has played a critical role in the development of these offering ideas as he has a strong understanding of tribal challenges related to energy efficiency, most of which stem from the lack of resources.

	Full details of the program offering are not available since, upon approval, we would want to involve the tribal leaders and housing authority staff in order to get buy-in. However, the list of possible options is provided below. These offerings are intended to be no- or low-cost to the customer in order to overcome barriers to participation due to lack of resources to support energy efficiency improvements. **Residential** Free Home Energy Assessment (if available, use tribe's own contractor and possibly purchase a blower door for the community) $1,500 towards home improvements identified during the assessment Free furnace and a/c tune-up Provide an energy saving pack to each home and install Offer education awareness collateral **Business** Free high-level assessment (either Focus or Mid-Market) Direct install of energy saving measures to those completing an assessment Offer discounted measure bundle Funding for improvements Enhanced incentives **Critical Infrastructure (schools, healthcare, water, sewer)** Free comprehensive energy assessment Funding for improvements Enhanced incentives Energy efficiency training scholarships **Community Reward** The idea of a community reward to incentivize the tribal community for their energy related efforts has been discussed. The reward would require input from the tribal community and would be offered for achieving specific goals or milestones, such as behavioral changes or number of projects completed within the tribal community. As mentioned earlier, one tribe would be selected for this initial offering. Based on the three tribes in NSPW service territory and reviewing each tribe's infrastructure, it was decided the Lac Courte Oreilles Band of Lake Superior Chippewa Indians (LCO Tribe) is the first choice. The LCO Tribe has their own school and community college, healthcare facility, fire station, wastewater treatment facility and many businesses. Their housing authority manages approximately 400 rental and homeowner units. They have a 20% unemployment rate, 27% of the households are below the Federal Poverty Level and 65% of multi-family occupants are making less than 80% of the median income of $26,000*.

	The cost for this initiative would be shared between Focus and NSPW, with the possibility of some dollars coming from OEI to help with customers using propane. Preliminary figures for NSPW's portion of offering this to the LCO Tribe is $100,000. The majority of the cost is for the additional incentives and project funding, with an additional $25,000 being budgeted for promotion, expenses, labor and evaluation. Even though the total projected spend is $100,000, NSPW is only proposing to increase the budget by $49,500. No additional dollars were added to the 'Commercial Labor' and 'Commercial Incentives' line items due to an underspend in those areas the past two years. See budget information in Sections Two and Three for more information on budget impacts. NSPW is seeking approval to pursue a collaborative initiative between Focus, the LCO Tribe (or an alternate tribe) and NSPW. Upon approval, NSPW and Focus could verify the LCO Tribe's interest in participating and could begin work on specific design elements of the program.
	*Source: 2019 Lac Courte Oreilles Community Assessment

New Transmission Lines

Instructions:

Provide data on all transmission construction expected to begin by December 31, 2028

Provide data on all lines with a nominal voltage greater than 69 kV, including upgrades and rebuilds of lines with a current nominal voltage less than 100 kV.

Provide data on all lines regardless of CPCN filing status.

For any application that DOES NOT have a CPCN application filed with the Commission OR which requires a new right-of-way, provide detaled information and any additional notes on the transmission corridors in the "Detail" column on the right.

SEA data collection pursuant to Wis. Admin. Code § PSC 111.43(1)(a) through (e).

*Under **Add a New Transmission Line** , enter the endpoints (substations) for the new line. Click "Add to List". Repeat the process for each new line. Once a line is added, fill in the blank boxes.*

For double circuit lines, enter each line seperately. For example, if a double circuit has voltages of 345 and 115, do not enter 345/115. When entering the second line of a double circuit, add a "(2)" after the endpoint in "Endpoint 2"

For lines with a cost estimate range, enter only the nominal cost estimate.

Estimated Nominal Cost is the sum of cost of the transmission line and associated substation modifications.

If the expected construction is in progress, enter the date the construction began.

Nothing on this form is expected to be confidential.

Endpoint 1 (Substation Name)	Endpoint 2 (Substation Name)	Midpoint Connections (if any)	Nominal Operating Voltage (kV)	Nominal Construction Voltage (kV)	Estimated or Actual Total Mileage	Estimated Nominal Cost ($)	Expected Construction Start Mn/Yr	Expected In-Service Date Mn/Yr	Required Substation Modifications	Detail
King	Eau Claire		345	345	63	38,400,000	22-Apr	24-Dec	None are planned at this time.	Rebuild on exisiting ROW, no CPCN.
Eau Claire	Arpin		345	345	80	28,300,000	22-Apr	24-Dec	None are planned at this time.	Rebuild on exisiting ROW, no CPCN.
Bayfront	Norrie	Saxon Pump	88	115	47	50,000,000	24-May	25-Jan	None are planned at this time.	Upgrade and Relocation. Rebuild and reroute this line southeast to Mellen area then northeast up to Ironwood area. CPCN; Filed in early 2021- Bayfront-Norrie/Gingles-Hurley
Gingles	Hurley		115	161	47	50,000,000	24-May	25-Jan	None are planned at this time.	Upgrade and Relocation. Rebuild and reroute this line southeast to Mellen area then northeast up to Ironwood area. CPCN; Filed in early 2021- Bayfront-Norrie/Gingles-Hurley
Str 140 (From Prentice)	Philips	Philips DPC	115	115	7.1	3,581,394	21-Jun	21-Nov	None are planned at this time.	Rebuild. Line rebuild on existing right of way. Starting at structure 140 and will end at Xcel Philips substation. Follow existing ROW
Str 54 (From Osprey)	Hawkins tap		115	115	5	3,482,702	22-Sep	22-Dec	None are planned at this time.	Rebuild. Line rebuild on existing right of way. Starting at structure 54 and will end at the Hawkins tap. No CA or CPCN; Follow existing ROW
Str 492 (From Eagle Point)	Pine Lake		115	115	23	2,528,616	22-Jan	22-Mar	None are planned at this time.	Rebuild. Line rebuild on existing right of way. Starting at structure 492 and will end at the Pine Lake substation. No CA or CPCN; Follow existing ROW
LaCrosse	Cooley		161	161	8.4	10,000,000	23-May	23-Jun	None are planned at this time.	Rebuild. Line rebuild on existing right of way through LAX marsh and City owned bluff parcels. No CA or CPCN; Follow existing ROW
Briggs Road	Mayfair		161	161	7.5	8,030,000	22-Mar	22-Aug	None are planned at this time.	Rebuild. Line rebuild on existing right of way, no CA/CPCN expected. Follow existing ROW
Mayfair	LaCrosse		161	161	3.7	3,160,000	22-Sep	23-Mar	None are planned at this time.	Rebuild. Line rebuild on existing right of way, no CA/CPCN expected. Follow existing ROW
Three Lakes	Willow River		115	115	5.7	2 070 360	22-Feb	22-Apr	None are planned at this time.	Rebuild. Line rebuild on existing right of way, no CA/CPCN expected. Follow existing ROW

New Transmission Lines: Detailed Information

Detailed information is required to be submitted for any application that DOES NOT have a CPCN application filed with the Commission OR which requires a new right-of-way.

NSPW RESPONSE:

NSPW is not submitting detailed information at this time as all new transmission line projects listed on Schedule 11 either have a CPCN application or will be constructed in existing right-of-way.

Environmental Compliance

Instructions:

In addition to this form, upload to ERF a detailed narrative description of the potential impacts anticipated for your organization to meet each of the Environmental Compliance rules, and any forthcoming environmental regulations.
Provide capital plan excerpts specific to the Environmental Compliance rule. When the document is uploaded to ERF, enter the ERF Reference Number in the box.
Include all planned capital expenditures for compliance costs for the next seven years
Under Primary Compliance Rule, select "N/A – Co-ownership" from the drop down list for plants co-owned by the utility, but where reporting is the responsibility of a different entity.
If more than one Type of Emission Control is used, click on "Notes" and add that information to the text box.
May be filed confidentially.

Unit Name	Primary Compliance Rule	Secondary Compliance Rule	Estimated Forecast Costs	Amount Spent To-Date	Total Estimated Costs	Type of Emission Control	Project Status	Confidential Status (Y/N)	PSC Ref # (if applicable)
[redacted]								Y	
								Y	
								Y	
								Y	

Northern States Power Company
5-ES-111
Schedule 12 Narrative
CONFIDENTIAL REDACTED

Environmental Compliance – Potential Impacts

In addition to this form, upload to ERF a detailed narrative description of the potential impacts anticipated for your organization to meet each of the Environmental Compliance rules, and any forthcoming environmental regulations.

NSPW RESPONSE:

[redacted]

Instructions
- Type company name into the light green box
- Scroll down to enter information for each year requested: 2019, 2020, and 2021
- Data entered for 2019 and 2020 shold represent twelve months of actuals. For 2021, report actual figures through September 30
- Provide aggregate data by DER and resource type, broken into the separate customer classes as labeled.
- "Installed capacity (kW)" and "Total MW" means the total capacity of DER installations per category, technology, and all installations, less retirements or cessations of self-supply
- Provide installed capacity/total MW in both AC and DC. If data is limited or unavailable for one metric, describe the limitations in the Notes column.
- For battery storage systems, report installed capacity/total MW as peak kW discharge.
- "Installation Count" means the number of DER installations per category, in-service and operating.
-"Utility Purchased (kWh)" means the total kWh purchased by the utility from DERs. Do not report energy consumption offset through net metering or net energy billing.
-"Utility Purchased ($)" means the total dollar value paid by the utility for purchases from DERs. Do not report energy consumption offset through net metering or net energy billing.
-For municipal utilities only, enter yes under "Reported on E-16?" column IF the resource was reported in the new annual report format implemented in 2015.
-Size categories and technology types are labelled in the boxes on the right.
-May be filed confidentially

Year: 2019

Company Name

Northern States Power Company

Residential

Type	Size Category	Installation Count	Installed Capacity (kW) (DC)	Installed Capacity (kW) (AC)	Utility Purchased (kWh)	Utility Purchased ($)	Reported on E-16	Notes:

Commercial

Type	Size Category	# of Installations	Total MW (DC)	Total MW (AC)	Utility Purchased kWh	Utility Purchased $	Reported in E-16	Notes:

*Include any Qualifying Facilities (PURPA)

Industrial

Type	Size Category	# of Installations	Total MW (DC)	Total MW (AC)	Utility Purchased kWh	Utility Purchased $	Reported in E-16	Notes:

*Include any Qualifying Facilities (PURPA)

Cooperative

Type	Size Category	# of Installations	Total MW (DC)	Total MW (AC)	Utility Purchased kWh	Utility Purchased $	Reported in E-16	Notes:

*Include any Qualifying Facilities (PURPA)

Independent Power Producer

Type	Size Category	# of Installations	Total MW (DC)	Total MW (AC)	Utility Purchased kWh	Utility Purchased $	Reported in E-16	Notes:

*Include any Qualifying Facilities (PURPA)

Year: 2020

Company Name

Northern States Power Company

Residential								
Type	Size Category	Installation Count	Installed Capacity (kW) (DC)	Installed Capacity (kW) (AC)	Utility Purchased (kWh)	Utility Purchased ($)	Reported on E-16	Notes:

Commercial								
Type	Size Category	# of Installations	Total MW (DC)	Total MW (AC)	Utility Purchased kWh	Utility Purchased $	Reported in E-16	Notes:

*Include any Qualifying Facilities (PURPA)

Industrial								
Type	Category	Installation	Total MW (DC)	Total MW (AC)	kWh	$	E-16	Notes:

*Include any Qualifying Facilities (PURPA)

Cooperative								
Type	Size Category	# of Installations	Total MW (DC)	Total MW (AC)	Utility Purchased kWh	Utility Purchased $	Reported in E-16	Notes:

*Include any Qualifying Facilities (PURPA)

Independent Power Producer								
Type	Size Category	# of Installations	Total MW (DC)	Total MW (AC)	Utility Purchased kWh	Utility Purchased $	Reported in E-16	Notes:

*Include any Qualifying Facilities (PURPA)

Year: 2021

Company Name

Northern States Power Company

Residential

Type	Size Category	Installation Count	Installed Capacity (kW) (DC)	Installed Capacity (kW) (AC)	Utility Purchased (kWh)	Utility Purchased ($)	Reported on E-16	Notes:

Commercial

Type	Size Category	# of Installations	Total MW (DC)	Total MW (AC)	Utility Purchased kWh	Utility Purchased $	Reported in E-16	Notes:

*Include any Qualifying Facilities (PURPA)

Industrial

Type	Size Category	# of Installations	Total MW (DC)	Total MW (AC)	Utility Purchased kWh	Utility Purchased $	Reported in E-16	Notes:

*Include any Qualifying Facilities (PURPA)

Cooperative

Type	Size Category	# of Installations	Total MW (DC)	Total MW (AC)	Utility Purchased kWh	Utility Purchased $	Reported in E-16	Notes:

*Include any Qualifying Facilities (PURPA)

Independent Power Producer

Type	Size Category	# of Installations	Total MW (DC)	Total MW (AC)	Utility Purchased kWh	Utility Purchased $	Reported in E-16	Notes:

*Include any Qualifying Facilities (PURPA)

Utility Backed Distributed Energy Resources - Community Projects

Instructions:

Report all utility backed/owned "community" DER projects such as community solar.
Report the type generating facility based on technology - e.g. Solar, Wind, Biogas, etc.
Report whether a facility is owned solely or partly by the utility, or whether the generating facility is owned by a third party.
For 2021, report actual figures from January 1 to September 20, 2019. (Note: Reported Jan 1 - Sept 30, 2021)
For 2022 and 2023 report forecasted values as known to the utility.
All 2019 data submitted for previous SEA represented 9 months of data and must be revised to reflect 12 months of data.
All 2020 data submitted in previous SEA represent a 12-month forecast and must be revised to reflect 12 months of actuals.
All 2021 data submitted in previous SEA represented 12-month forecast and must be revised to reflect 9 months of actuals (January 1 to September 30).
Nothing on this form is expected to be confidential

Year	System Name	County	Municipality	Ownership	Technology Category	Installation Size (kW)	Subscribed Capacity (kW)	Energy Production (kWh)	Subscribers (Customers) *(See Note Below)*
2019 Actual	Ashland Solar Garden	Ashland	City of Ashland	Third Party	Solar	1,000	1,000	438,276.54	154
2020 Actual	Ashland Solar Garden	Ashland	City of Ashland	Third Party	Solar	1,000	996.2	989,300.00	151
2021 (Jan. Through Sept. 30 Actuals)	Ashland Solar Garden	Ashland	City of Ashland	Third Party	Solar	1,000	1,000	898,320.00	140
2022 Forecast	Ashland Solar Garden	Ashland	City of Ashland	Third Party	Solar	1,000	1,000	1,093,530.00	142
2023 Forecast	Ashland Solar Garden	Ashland	City of Ashland	Third Party	Solar	1,000	1,000	1,093,530.00	142
2019 Actual	Eau Claire Solar Garden	Eau Claire	City of Eau Claire	Third Party	Solar	1,000	1,000	978,223.24	154
2020 Actual	Eau Claire Solar Garden	Eau Claire	City of Eau Claire	Third Party	Solar	1,000	1,000	1,210,620.00	151
2021 (Jan. Through Sept. 30 Actuals)	Eau Claire Solar Garden	Eau Claire	City of Eau Claire	Third Party	Solar	1,000	1,000	875,418.00	140
2022 Forecast	Eau Claire Solar Garden	Eau Claire	City of Eau Claire	Third Party	Solar	1,000	1,000	1,188,922.00	142
2023 Forecast	Eau Claire Solar Garden	Eau Claire	City of Eau Claire	Third Party	Solar	1,000	1,000	1,188,922.00	142
2019 Actual	LA Crosse Solar Garden	Monroe	Village of Cashton	Third Party	Solar	1,000	1,000	1,174,994.67	154
2020 Actual	LA Crosse Solar Garden	Monroe	Village of Cashton	Third Party	Solar	1,000	1,000	1,056,410.00	151
2021 (Jan. Through Sept. 30 Actuals)	LA Crosse Solar Garden	Monroe	Village of Cashton	Third Party	Solar	1,000	1,000	1,134,491.00	140
2022 Forecast	LA Crosse Solar Garden	Monroe	Village of Cashton	Third Party	Solar	1,000	1,000	1,248,020.00	142
2023 Forecast	LA Crosse Solar Garden	Monroe	Village of Cashton	Third Party	Solar	1,000	1,000	1,248,020.00	142

NOTE: Customers subscribe to a community solar garden program. Subscriptions are not specific to a single solar garden (Ashland, Eau Claire, LaCrosse). Therefore, the number of subscribers listed for each solar garden (Ashland, Eau Claire, and LaCrosse) is the same as the total number of subscribers for the 3 garden program. (Example: Total number of subscribers in the community solar garden program in 2019 is 154. Each of those 154 customers are reported as subscribers in all 3 gardens. It is not appropriate to total the 3 solar garden number of subscribers to get a total number of solar garden program subscribers. (154 + 154 + 154 ≠ 462).

Demand Response Programs

Program Title	Electric Rate Savings (commercial)		Tariff Name & Sheet	Service - Sheets E35 through E40.1	Date Established	1985
Program Type	Interruptible Load	If other please describe	DR Event Criteria	Both Economic and Reliability Events	If other please describe	
Short Program Description	Electric Rate Savings is an interruptible load program curtailing for commercial and industrial customers. Tariff: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/WI/2We_Section_2New.pdf - Pages 52 through 57					
Total # of Customers Enrolled	271		Customer kW Limit	N/A	Program kW Limit	58,070
Annual Event Limit	10					

		Historical							Forecasted						
		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Capacity (MW)		66.42	66.51	73.39	70.41	88.78	58.07	64.49	57.86	63.00	68.00	73.00	74.50	76.00	77.50
Demand-side (MW)	Applicable														
Enrollment (# Customers)		247	246	246	258	263	269	273	271	275	280	285	290	300	300
DR Compensation Type (Select One)		$/kW rate	If other please describe												
DR Compensation $ Value (marginal $/unit)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Admin Costs ($/yr)		$16,000	$16,000	$16,000	$16,000	$16,000	$16,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000	$12,000
DR Program Payments to Customers ($/yr)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Supply-side (MW)	Not Applicable														
Enrollment (# Customers)		0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR Compensation Type (Select One)		<Select>	If other please describe												
DR Compensation $ Value (marginal $/unit)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Admin Costs ($/yr)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Payments to Customers ($/yr)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Comments: *Demand management program offering customer discounts for contracted interruptible load relief.*

	Historical							Forecasted						
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Dispatched (MW)	66.42	66.51	73.39	70.41	88.78	58.07	69.49	57.86	63.00	68.00	73.00	74.50	76.00	77.50
	(aggregate demand response dispatched)													
# of Dispatched Events	1	1	1	1	1	1	1	1	3	3	5	5	7	7
	(# of demand response events during the year, resources called upon)													

Comments: *In recent years we have had at least one control event per year as a systems test. We anticipate future years will bring more frequent interruptions as renewables become a greater component of generation.*

Program Title	AC Rewards	Tariff Name & Sheet	Farm Service-Sheet E16; Residential and Farm Managed	Date Established	2019
Program Type	Direct Load Control / If other please describe	DR Event Criteria	Both Economic and Reliability Events / If other please describe		
Short Program Description	AC Rewards eligible residential customers are provided with incentives to install qualifying Wi-Fi connected thermostats in exchange for participation in load management events. Tariff: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/WI/2We_Section_2New.pdf - Pages 1, 10, 11, 12				
Total # of Customers Enrolled	912	Customer kW Limit	N/A	Program kW Limit	N/A / Annual Event Limit: N/A

	Historical							Forecasted						
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Capacity (MW)	N/A	N/A	N/A	N/A	N/A	< 1	< 1	1	1	2	3	3	4	4
Demand-side (MW) Applicable														
Enrollment (# Customers)	N/A	N/A	N/A	N/A	N/A	58	182	912	1650	2400	3000	3500	4000	4500
DR Compensation Type (Select One)	Time Payr / If other please describe													
DR Compensation $ Value (marginal $/unit)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Admin Costs ($/yr)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Payments to Customers ($/yr)	N/A	N/A	N/A	N/A	N/A	$1,175	$4,550	$22,800	$41,250	$60,000	$75,000	$87,500	$100,000	$112,500
Supply-side (MW) ot Applicable														
Enrollment (# Customers)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR Compensation Type (Select One)	<Select> / If other please describe													
DR Compensation $ Value (marginal $/unit)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Admin Costs ($/yr)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Payments to Customers ($/yr)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Comments: *Customers must choose between AC Rewards and Saver Switch they cannot be on both programs.*

	Historical							Forecasted						
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Dispatched (MW)	N/A	N/A	N/A	N/A	N/A	< 1	< 1	1	1	2	3	3	4	4
	(aggregate demand response dispatched)													
# of Dispatched Events	N/A	N/A	N/A	N/A	N/A	0	1	2	3	3	5	5	5	5
	(# of demand response events during the year, resources called upon)													

Comments: *In recent years we have had one or two control event per year as a systems test. We anticipate future years will bring more frequent interruptions as renewables become a greater component of generation.*

Program Title	Saver's Switch (Residential AC)							Tariff Name & Sheet	Farm Service-Sheet E16; Residential and Farm Managed			Date Established	1990s		
Program Type	Direct Load Control	If other please describe						DR Event Criteria	Both Economic and Reliability Events	If other please describe					
Short Program Description	Saver's Switch is a direct load control program curtailing AC load (and enrolled electric water heaters). Tariff: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/WI/2We_Section_2New.pdf - Pages 1, 10, 11, 12														
Total # of Customers Enrolled	18,212			Customer kW Limit	N/A			Program kW Limit	N/A			Annual Event Limit	N/A		

		Historical							Forecasted							
		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Capacity (MW)		8.00	8.30	9.70	7.50	7.50	9.30	9.80	10.00	10.00	10.00	10.00	11.00	11.00	11.00
Demand-side (MW)	Applicable														
Enrollment (# Customers)		17,116	17,553	17,819	17,511	17,768	18,195	18,212	18,500	18,750	19,000	19,250	19,500	19,750	20,000
DR Compensation Type (Select One)		Other	Customers receive $6/mo (June - September) for participating.												
DR Compensation $ Value (marginal $/unit)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Admin Costs ($/yr)		$322,120	$281,850	$481,489	$509,092	$173,179	$395,226	$303,201	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000	$250,000
DR Program Payments to Customers ($/yr)		$410,784	$421,272	$427,656	$420,264	$426,432	$436,680	$437,088	$440,000	$440,000	$440,000	$440,000	$450,000	$450,000	$450,000
Supply-side (MW)	Not Applicable														
Enrollment (# Customers)		0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR Compensation Type (Select One)		<Select>	If other please describe												
DR Compensation $ Value (marginal $/unit)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Admin Costs ($/yr)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Payments to Customers ($/yr)		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Comments: *Demand management program offering DLC via one-way pager operated switches.*

	Historical							Forecasted						
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Dispatched (MW)	N/A	8.30	9.70	7.50	7.50	9.30	9.80	10.00	10.00	10.00	10.00	11.00	11.00	11.00
	(aggregate demand response dispatched)													
# of Dispatched Events	0	1	1	1	1	1	1	1	3	3	5	5	7	7
	(# of demand response events during the year, resources called upon)													

Comments: *In recent years we have had one control event per year as a systems test. We anticipate future years will bring more frequent interruptions as renewables become a greater component of generation.*

Program Title	Saver's Switch (Residential Water Heaters)		Tariff Name & Sheet	Farm Service-Sheet E16; Residential and Farm Managed	Date Established	1990s
Program Type	Direct Load Control	If other please describe	DR Event Criteria	Both Economic and Reliability Events	If other please describe	
Short Program Description	Saver's Switch is a direct load control program curtailing AC load (and enrolled electric water heaters). Tariff: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/WI/2We_Section_2New.pdf - Pages 1, 10, 11, 12					
Total # of Customers Enrolled	1,551		Customer kW Limit	N/A	Program kW Limit	N/A
Annual Event Limit	N/A					

	Historical							Forecasted						
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Capacity (MW)	0.58	0.58	0.52	0.50	0.51	0.52	0.31	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Demand-side (MW) Applicable														
Enrollment (# Customers)	2,882	2,922	2,614	2,513	2,555	2,585	1,551	1,500	1,500	1,500	1,500	1,500	1,500	1,500
DR Compensation Type (Select One)	Other	Customers receive $2/month for participating												
DR Compensation $ Value (marginal $/unit)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Admin Costs ($/yr)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Payments to Customers ($/yr)	$69,168	$70,128	$62,736	$60,312	$61,320	$62,040	$37,224	$36,000	$36,000	$36,000	$36,000	$36,000	$36,000	$36,000
Supply-side (MW) ot Applicable														
Enrollment (# Customers)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR Compensation Type (Select One)	<Select>	If other please describe												
DR Compensation $ Value (marginal $/unit)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Admin Costs ($/yr)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Payments to Customers ($/yr)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Comments: *Participation in WH program requires participation in AC as well. Beyond incentives, costs are not available for the WH program. Those are include in WH.*

	Historical							Forecasted						
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Dispatched (MW)	N/A	0.58	0.52	0.50	0.51	0.52	0.31	0.30	0.30	0.30	0.30	0.30	0.30	0.30
	(aggregate demand response dispatched)													
# of Dispatched Events	0	1	1	1	1	1	1	1	3	3	5	5	7	7
(# of demand response events during the year, resources called upon)														

Comments: *In recent years we have had one control event per year as a systems test. We anticipate future years will bring more frequent interruptions as renewables become a greater component of generation. The projected load reduction is 0.2kW per enrolled water heater.*

Program Title	Saver's Switch (Commercial)							Tariff Name & Sheet	Commercial Load Control Rider - Sheet E24.50			Date Established	1990s		
Program Type	Direct Load Control	If other please describe						DR Event Criteria	Both Economic and Reliability Events	If other please describe					
Short Program Description	Saver's Switch is a direct load control program curtailing AC load (and enrolled generators). Tariff: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/WI/2We_Section_2New.pdf - Page 22														
Total # of Customers Enrolled	1,068			Customer kW Limit	N/A			Program kW Limit	N/A			Annual Event Limit	N/A		

	Historical							Forecasted						
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Capacity (MW)	7.20	6.70	7.20	8.00	6.20	6.10	6.20	6.00	6.00	6.00	6.00	6.00	6.00	6.00
Demand-side (MW) Applicable														
Enrollment (# Customers)	717	812	865	920	955	1,050	1,068	1,075	1,100	1,125	1,150	1,175	1,200	1,225
DR Compensation Type (Select One)	Other	Customers receive $3/kW per month for participating.												
DR Compensation $ Value (marginal $/unit)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Admin Costs ($/yr)	$142,641	$223,672	$234,231	$145,622	$216,600	$93,485	$30,209	$125,000	$205,000	$205,000	$205,000	$205,000	$205,000	$205,000
DR Program Payments to Customers ($/yr)	$259,200	$241,200	$259,200	$288,000	$223,200	$219,600	$223,200	$223,000	$223,000	$223,000	$223,000	$223,000	$223,000	$223,000
Supply-side (MW) ot Applicable														
Enrollment (# Customers)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DR Compensation Type (Select One)	<Select>	If other please describe												
DR Compensation $ Value (marginal $/unit)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Admin Costs ($/yr)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
DR Program Payments to Customers ($/yr)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Comments: *Demand management program offering DLC via one-way pager operated switches.*

	Historical							Forecasted						
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Dispatched (MW)	N/A	6.70	7.20	8.00	6.20	6.10	6.20	6.00	6.00	6.00	6.00	6.00	6.00	6.00
	(aggregate demand response dispatched)													
# of Dispatched Events	0	1	1	1	1	1	1	1	3	3	5	5	7	7
	(# of demand response events during the year, resources called upon)													

Comments: *In recent years we have had one control event per year as a systems test. We anticipate future years will bring more frequent interruptions as renewables become a greater component of generation.*

Carbon Reduction Activities

- *A description of any carbon reduction goals established for the provider, which specifies:*
  - *The baseline year used for establishing the goal and the year (or years) in which certain reduction goals are to be reached; and*
  - *The magnitude of the reduction goal, expressed as both a percentage and million metric tons of CO_2 ($MMTCO_2$).*

Xcel Energy: In December 2018 Xcel Energy (the Company) announced a company-wide goal to reduce CO_2 emissions from the electricity provided to its customers to 80% below 2005 levels by 2030, and an aspiration to provide 100% carbon-free electricity to customers by 2050. These goals are at the company-wide level for all eight states served by Xcel Energy. The baseline for these company-wide goals is 2005, when Xcel Energy's total carbon dioxide emissions from owned and purchased electricity serving customers were 78.2 million metric tons of CO_2 ($MMTCO_2$). By 2030, the 80% reduction goal translates to 15.6 $MMTCO_2$ from electricity provided to Xcel Energy customers in all eight states combined.

Northern States Power Company: Customers in Wisconsin are served by one of Xcel Energy's four operating companies, Northern States Power Company, a Wisconsin corporation (NSPW). NSPW, together with Northern States Power Company, a Minnesota corporation, (NSPM) plans and operates an integrated five-state (Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan) system (the NSP System). NSPW and NSPM share production and transmission resources for the NSP System pursuant to a Federal Energy Regulatory Commission (FERC)-approved Interchange Agreement. In July 2019, NSPM filed a 15-year integrated resource plan for the NSP System, titled the *Upper Midwest Energy Plan*,[1] that would result in a reduction of carbon dioxide emissions to 3.7 $MMTCO_2$ by 2030, a reduction of 86% relative to the NSP System baseline emissions of 25.4 $MMTCO_2$ in 2005.

NSPW: The Interchange Agreement specifies that NSPW and NSPM are allocated their proportionate share of costs for the NSP System according to the portion of the system that they represent for demand and load. NSPW represents approximately 16% of the NSP System and therefore is allocated approximately 16% of costs and resources of the NSP System. Solely for the purpose of this Supplemental Data Request, this response uses the FERC Interchange Agreement cost allocator to similarly allocate 16% of total NSP System CO_2 emissions to NSPW, and to estimate carbon reductions at the NSPW level.[2]

[1] See https://www.xcelenergy.com/company/rates_and_regulations/resource_plan_overview/upper_midwest_energy_plan.

[2] The actual percentage allocators used for the Interchange Agreement are updated annually for demand costs and monthly for energy costs, based on actual demand and energy data. The 16 percent used here is an approximation.

In Xcel Energy's carbon reporting – for example, the Company's annual third-party verified reporting to The Climate Registry,[3] as well as voluntary reporting in the Company's Corporate Responsibility Report and other formats – Xcel Energy *does not* generally use the Interchange Agreement to allocate emissions between NSPM and NSPW. The Company simply reports emissions at the NSP System level. However, at the request of Commission staff, for the purposes of this Supplemental Data Request the 16% Interchange Agreement allocator for NSPW is used to estimate baseline year and target year emissions attributable to electricity serving NSPW customers. There are two caveats to this approach. First, it does not imply 16% of the emissions are from sources physically located in Wisconsin or Michigan[4]; only that following the logic of the Interchange Agreement, about 16% of the carbon dioxide is attributable to serving customers in those states. Second, this response assumes the approximately 16% allocator that exists today a) was approximately the same in the baseline year of 2005 and b) remains approximately the same in future years such as 2020, 2026, and 2030. NSPW has not attempted to estimate an allocator specific to those years.

With those assumptions, the NSPW portion of NSP System 2005 baseline emissions would be 4.1 $MMTCO_2$. Assuming approval of the *Upper Midwest Energy Plan*, those emissions from electricity serving NSPW customers would decline to 0.59 $MMTCO_2$ by 2030, a reduction of 86% relative to 2005.

- *Data specifying carbon emission levels on the provider's system in CY 2020, which permits clear analysis of progress to date towards any carbon reduction goals, in both percentage and $MMTCO_2$ terms. The system-wide 2020 data should be consistent with the facility-level data on 2020 CO2 emissions provided in Schedule 8A, and the response to this supplementary data request should clearly explain how the system-wide totals can be reconciled with the facility-level data.*

As of the end of CY 2020,[5] NSP System emissions from owned generation and purchased power serving customers were 11.5 $MMTCO_2$, a reduction of 55% relative to 2005. Using the Interchange Agreement allocator, emissions from electricity serving NSPW customers were approximately 1.8 $MMTCO_2$ in that year (same percent reduction from 2005 as for the NSP System overall).

- *Projected carbon emission levels on the provider's system in CY 2022, CY 2024, CY 2026 and in CY 2028, which specifies projected progress towards any carbon reduction goals for both years, in both percentage and $MMTCO_2$ terms.*

By the end of CY 2022, assuming the *Upper Midwest Energy Plan* is approved, NSP System carbon dioxide emissions are forecast to decline to 9.4 $MMTCO_2$, a reduction of 63% relative to 2005. Using the

[3] See https://www.theclimateregistry.org/.
[4] Michigan load represents approximately 2% of NSPW's total company load, or 0.3% of the NSP System.
[5] Xcel Energy annually reports its greenhouse gas emissions to The Climate Registry, and these emission reports are independently verified by a third-party verifier. Third-party verification is not yet complete for CY 2020 emissions, so the reported total could change, although any change is likely to be small.

Interchange Agreement allocator, emissions from electricity serving NSPW customers would be approximately 1.5 $MMTCO_2$ in that year.

By the end of CY 2028, assuming the *Upper Midwest Energy Plan* is approved, NSP System carbon dioxide emissions are forecast to decline to 5.8 $MMTCO_2$, a reduction of 77% relative to 2005. Using the Interchange Agreement allocator, emissions from electricity serving NSPW customers would be approximately 0.9 $MMTCO_2$ in that year.

- *A narrative explaining the anticipated causes behind projected changes in carbon emissions levels between 2020 and 2028. This narrative should address the relationship between changes in carbon emissions levels and the data submitted through the standardized SEA schedules regarding unit retirements, new generating facilities, purchases, emissions control projects, energy efficiency, demand response, and utility-backed distributed energy resources. In specific, the narrative should explain in detail the impacts on projected emissions from generation additions and retirements, with reference to the 2002 facility emissions data provided in Schedule 8A.*

Carbon dioxide emission reductions between 2020 and 2028 will be primarily attributable to five main drivers: wind additions, solar additions, coal unit retirement and reduced operation prior to retirement, demand-side management, and declining CO_2 intensity of market power purchases.

Wind additions. The NSP System is currently in the process of completing a large wind portfolio build-out, which we expect will bring us to a total of over 4,500 MW of wind on our system by the end of 2021 or early 2022. We also are beginning a process of repowering approximately 900 MW of older wind farms already on our system, in order to increase their output and capture additional policy incentives, to the benefit of our of customers. These repowering projects are expected to begin in-servicing in 2022 and be completed by 2025. Finally, our most recent proposed Integrated Resource Plan includes development of new greenfield wind capacity, beginning in the late 2020s. In total, these actions will increase the share of electricity coming from wind and push down dispatch of coal and natural gas units, thereby reducing CO_2 emissions.

Solar additions. The Company anticipates significant utility-scale solar additions beginning in 2024, with about 1,300 MW proposed to be added in 2024 and 2025 under the *Upper Midwest Energy Plan*. These projects will begin to reduce CO_2 emissions (by displacing coal and gas generation) near the end of the period in question. In the nearer term, small-scale solar is expected to continue to be added to the system. In total, the Company expects to add approximately 2,600 MW of solar to our system by 2028, across large- and small-scale projects.

Coal retirement and reduced operations. The retirement of Sherburne County Units 2 (in 2023) and 1 (in 2026) are already approved under the Company's prior (2016-2030) Upper Midwest integrated resource plan. These retirements will significantly reduce CO_2 emissions in 2023 and again in 2026. Prior to unit retirement, it is possible these units will operate at reduced levels, which would also reduce CO_2.

Demand-side management (energy efficiency and demand response) has been an effective strategy to reduce generation from existing, and reduce the need for new, fossil-fired units. Under the *Upper*

Midwest Energy Plan, the Company expects to expand these measures. For example, annual energy savings at the NSP System level would grow to on average 380 GWh or 4.4% per year, reducing generation and emissions from CO_2-emitting units.

Lower-carbon purchased power. Finally, the Company expects CO_2 intensity to decline throughout MISO as coal units retire and renewable energy continues to expand. This will reduce the CO_2 added to the overall NSP System portfolio by MISO market purchases.

The figure below depicts total CO_2 from the NSP System since 2005 and projected forward to 2030.

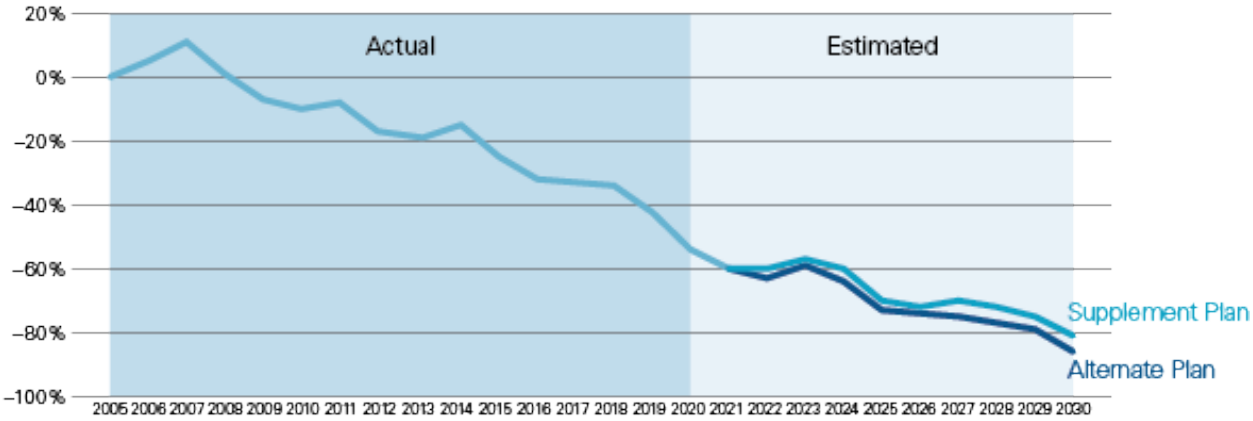

Figure 1. CO_2 emissions from the NSP System. 2005 = 25.4 $MMTCO_2$. 2020 = 11.5 $MMTCO_2$. 2030 = 3.7 $MMTCO_2$. See text for the share of CO_2 each year serving NSPW customers.

What is included in these carbon estimates?

Xcel Energy's greenhouse gas reporting follows The Climate Registry's *Electric Power Sector Protocol* and is very comprehensive, including CO_2 from owned power plants, power purchase agreements, and purchases in the MISO market. The Company includes CO_2 from MISO market purchases, but deducts CO_2 from trade margin sales (short-term sales of excess energy into the MISO market), since this energy does not serve Xcel Energy's customers, and if the energy purchasers report this CO_2, including it in the Company's reporting would result in double-counting.

The reported figures include CO_2 from electric generating units only, not other greenhouse gases; however, methane and nitrous oxide from power generation add less than ½ of one percent to total CO_2-equivalent emissions even after accounting for the higher global warming potentials of these gases.

Reliability Impacts of Potential Unit Retirements

Due to the continued significance of unit retirements for the evolution of Wisconsin's electric system, the Commission again requests Attachment Y2 and Y correspondence for SEA 2028.

Providers must submit:

• All documents associated with Attachment Y2 and Attachment Y filings submitted to or received from MISO in CY 2020 and CY 2021.

• All documents submitted to or received from MISO associated with Attachment Y2 and Attachment Y filings regarding a retirement proposed to occur on a date within the SEA data collection period (CY 2019-CY 2028), to the extent those documents are not already identified through the first request.

NSPW RESPONSE:

Within CY 2020 and CY 2021, NSPW has not submitted to or received from MISO any documents associated with Attachment Y2 and/or Attachment Y filings for generation located in Wisconsin or used specifically for Wisconsin purposes for CY 2019-CY 2028.

Utility Resource Planning

Providers must submit (as one or more documents) the following information:

• A narrative description of the driving factors behind additions and retirements, including an explanation of the rationales for each retirement, and the role of new generation additions, as well as other considerations such as forecasted customer demand, in ensuring the utility meets future capacity and generation needs. This narrative should also explain the influence of utilities' carbon reduction goals on their decisions.

• An explanation of the analysis procedures used by the utility to determine addition and retirement decisions, including the analytical models used, the rationale for selection of those models, and the methods used by the utility to ensure accurate and reliable modeling results;

• A description of the goals and standards used by the utility to set initial parameters for modeling, which may include but should not be limited to its definition of standards for maintaining system reliability, required reserve margins for resource adequacy, and the application of utility carbon reduction goals.

• Specification of the key input assumptions used to model system and market conditions, as well as any alternative assumptions used to conduct sensitivity analysis on the effects of different generation alternatives.

    o This specification shall include a detailed description of how the provider accounts for any existing renewable energy offerings, including but not limited to community solar and renewable energy riders.

• Specific description of all generation scenarios considered in analysis.

A presentation of modeling results that explains how the utility selected the proposed generation scenario reflected in its reported additions and retirements, and how the utility concluded this scenario was superior to other scenarios considered.

NSPW RESPONSE:

Northern States Power Company-Wisconsin (NSPW) operates in an integrated generation and transmission system with Northern States Power Company-Minnesota (NSPM), together the NSP System. The NSP System serves Xcel Energy customers in NSPW and NSPM across five states; Wisconsin, Michigan, Minnesota, North Dakota, and South Dakota. Xcel Energy has statutory obligations in three states (Minnesota, Michigan, and North Dakota) to conduct integrated resource planning. In response to those statutory obligations, Xcel Energy files an Upper Midwest Integrated Resource Plan (IRP) for the

entire NSP System. In 2019, NSPM filed a 2020-2024 IRP in Minnesota (Docket No. E002/RP-19-368) and NSPW filed a matching IRP in Michigan (Docket No. U-20599). North Dakota's statutory requirement was recently enacted and NSPM has filed its first IRP in North Dakota in 2021[1].

The Strategic Energy Assessment (SEA) utility resource planning information requested by Commission staff is publicly available in NSPM's IRP filings. NSPM made an initial IRP filing on July 1, 2019[2] which was later updated by a Supplement filing and Reply Comments. NSPM filed the Supplement to the initial IRP filing on June 30 ,2020[3] and Reply Comments proposing an Alternative Plan on June 25, 2021.[4] A decision by the Minnesota Commission is still pending. In Michigan, the Public Service Commission approved our Initial Plan on February 6, 2020[5] and required us to make a compliance filing within 60 days after the Minnesota Commission makes a determination on the IRP that includes, at a minimum, a high-level summary of the outcome of the NSPM IRP decision(s), any potential effects on Michigan customers, the proposed timeline of its next filing in Minnesota, and the proposed timeline of its next filing in Michigan. Below are excerpts from the executive summaries provided in the NSPM IRP Supplemental filing and Reply Comments. Also provided are additional references to specific portions of the NSPM filings where detailed responses can be found which we believe address the SEA data requests related to utility resource planning.

Our initial filing in July of 2019 – which accounted for more variables and changes than any other previous Xcel Energy resource plan – proposed a resource mix that achieved some of the most ambitious carbon reduction goals of any utility in the United States: an 80 percent reduction by 2005 levels by 2030. In preparing the Supplement and Reply Comments, the Company conducted extensive additional capacity expansion modeling using both Strategist, a tool we have historically relied on, and EnCompass, a new tool that provides the additional capability of modeling our system on an hourly basis. Our Alternate Plan builds upon the Company's vision for the future of our system that was included in our initial and Supplement Plans, achieving even higher levels of carbon reduction: over 85 percent by 2030.

The Alternate Plan continues to include the following core components included the initial and Supplement filings:

- Elimination of coal-fired generation from our system by 2030;
- Seasonal dispatch of Sherco Unit 2 and King until 2023, and economic dispatch for King until its proposed retirement in 2028;
- Acquisition of nearly 6,000 MW of utility-scale wind and solar by the end of the 15-year planning period;

[1] Case No. PU-19220
[2] Docket No. E002/19-368 Document ID 20197-154051-01.
[3] Docket No. E002/19-368 Document ID 20206-164371-01.
[4] Docket No. E002/19-368 Document ID 20216-175386-01.
[5] Case No. U-20599

- A substantial increase in Energy Efficiency (EE) savings and Demand Response (DR) resources; and
- Extending operation of the Monticello nuclear plant to 2040 and continuing operation of Prairie Island at least until the end of its operating license in 2033/2034.

The main changes to highlight in the Alternate Plan as compared to our Supplement Plan are as follows:

- Elimination of the planned Sherco combined cycle gas plant;
- Reutilization of interconnections at retired Sherco and King coal sites, which enables significant solar and wind additions as well as some hydrogen-capable combustion turbine (CT) resources; and
- Beginning a process to shift our current emergency system restoration (blackstart) plans from our current centralized restoration approach to a zonal restoration approach.

Detailed responses to SEA questions can be found at the following references in NSPM IRP filings:

- Description of driving factors behind additions and retirements and influence of carbon reduction goals
    - Alternate Plan: Reply Comments in Docket No. E002/19-368 Document ID 20216-175386-01 Section 1 Part I (Pages 4 - 14)
    - Action Plans: Reply Comments in Docket No. E002/19-368 Document ID 20216-175386-01 Section 1 Part III (Pages 23 - 27)
    - Modeling Framework and Results: Supplemental Filing in Docket No. E002/19-368 Document ID 20206-164371-01 Section 2 (Pages 12 – 25)
- Forecasted customer demand
    - Demand and Energy Forecast: Reply Comments in Docket No. E002/19-368 Document ID 20216-175386-01 Section 6 Part I (Pages 161 - 170), and Supplemental Filing Document ID 20206-164371-01 Attachment A Part II (Pages Att A. 19-36)
- Explanation of analysis used to determine addition and retirement decisions
    - Modeling Framework and Results: Supplemental Filing in Docket No. E002/19-368 Document ID 20206-164371-01 Section 2 (Pages 12 – 25) and Initial Filing Document ID 20197-154051-01 Chapter 5 (pages 97 – 106)
- A description of goals and standards used to set initial model parameters
    - Updates to Assumptions in the Alternate Plan: Reply Comments in Docket No. E002/19-368 Document ID 20216-175386-01 Section 1 Part II (Pages 14 - 23)
    - Reliability: Reply Comments in Docket No. E002/19-368 Document ID 20216-175386-01 Section 2 (Pages 30 – 53)
    - System Restoration and Blackstart: Reply Comments in Docket No. E002/19-368 Document ID 20216-175386-01 Section 3 (Pages 54 – 82)
    - MISO Reserve Margin and Capacity Accreditation: Supplemental Filing in Docket No. E002/19-368 Document ID 20206-164371-01 Section 2 (Pages 21 – 22)
    - Meeting Renewable Energy Requirements and Goals: Initial Filing Document ID 20197-154051-01 Chapter 3 (pages 59 – 62)

- Specification of key input assumptions used to model system and market conditions and sensitivities including explanation of accounting of renewable energy offerings
    - Modeling Inputs and Assumptions: Reply Comments in Docket No. E002/19-368 Document ID 20216-175386-01 Appendix A (Pages 1 – 35)
    - Modeling Framework and Results: Supplemental Filing in Docket No. E002/19-368 Document ID 20206-164371-01 Section 2 (Pages 12 – 25)
    - Distributed Energy Resource Forecasts: Supplemental Filing in Docket No. E002/19-368 Document ID 20206-164371-01 Attachment A Part III (Pages 37 – 44)
- Specific description of all generation scenarios considered
    - Modeling and Rebuttal: Reply Comments in Docket No. E002/19-368 Document ID 20216-175386-01 Section 4 (Pages 83 – 156), Supplemental Filing Document ID 20206-164371-01 Section 2 (Pages 12 – 25), and Initial Filing Document ID 20197-154051-01Chapter 5 (pages 97 – 106)